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Swellable And Inflatable Packers Provide Annular Isolation In Multizone Horizontal Laterals

By Tim Davis and Doug McCrady

HOUSTON–Many "poor" oil and gas prospects–particularly ultralow-permeability unconventional rocks such as shales and tight sands–become economic successes when hydraulic fractures are created in the pay zone. The fractures allow a single well bore to contact many thousands of square feet of reservoir.

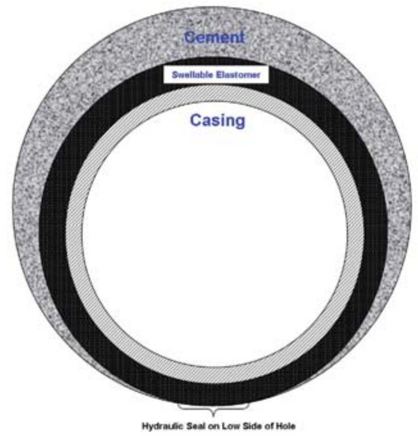
There are numerous factors to consider when designing and creating hydraulic fractures. One key factor is controlling where the hydraulic fractures are placed; or in other words, knowing where the fracture fluid goes once it exits the casing, and how each set of fractures is isolated from another.

The tried and proven method that is most often used to achieve annular isolation is filling the annular space with cement. This is the preferred method for vertical wells. Today, however, many tight reservoirs that require stimulation to achieve economic production rates are no longer drilled with vertical wells, but are using horizontal well technology to increase production, recovery efficiency and reserves. Horizontal drilling also is becoming the preferred method in many conventional reservoirs where hydraulic fracturing is required, such as in the Permian Basin.

However, the largest increase in horizontal drilling is taking place in unconventional reservoirs, where lateral lengths routinely exceed 4,000 feet.

FIGURE 1

Swellable Elastomer to Seal Low Side of Hole



An unconventional reservoir is defined as a formation with a large areal extent with no significant impact by a water leg or water drive. Examples of unconventional reservoirs are shales, basin-centered or tight gas sands, and coalbed methane. These reservoirs often contain large volumes of hydrocarbons, but are also generally characterized by very low permeabilities. Some are very tight with permeability in the micro- to nano-Darcy range. Additionally, many unconventional reservoirs have a high degree of heterogeneity.

Horizontal well bores treated with multistage frac jobs not only access much more productive reservoir rock, but create fractures that "reach out and touch" the better quality rock that a single well bore may miss.

Annular Isolation

In standard applications, annular isolation is required to support casing as well as isolate production from unwanted zones. In the case of horizontal wells, casing support typically is not a requirement. Isolation from unwanted zones usually is no longer a consideration, since a horizontal lateral is kept within the zone of interest. The primary reason for annular isolation in a horizontal well that requires hydraulic fracture treatment is to provide a positive annular barrier to contain the created fracture within a desired interval.

Early in the life of horizontal drilling, annular isolation for hydraulic fracture treatments was primarily achieved by filling the annulus with cement. In almost all scenarios for vertical wells, cement is the best annular isolation approach. And early in the development of horizontal drilling technology, there really were no viable alternatives to cementing, either. Cementing in horizontal well bores can be difficult. Centralizing the pipe is necessary to get sufficient cement sheath thickness on the low side of the hole and provide good flow mechanics to assure proper hole cleaning prior to cementing. Sufficient cement sheath thickness is needed to provide the isolation needed to contain a fracture treatment.

In long laterals, however, centralization is usually not an option because of the difficulties centralizers can create in getting a casing string to bottom. One possible solution to ensure that the low side of the well bore is isolated is to use a swellable packer. The intent is that the cement will occupy the annular space except at the low side of the hole (Figure 1). The swellable elastomer will absorb fluid, creating swell pressure and a hydraulic seal on the low side of the hole. Since it is only the low side of the hole that the swellable packer is intended to seal, the outside diameter of the packer can be minimized for maximum clearance during installation.

Technological solutions for annular isolation include:

- Chemical packers;
- Mechanical packers;
- Swellable packers; and
- Inflatable packers.

Chemical packers have had great success when used with slotted liners and stand-alone screens to shut off gas and/or water. Although there have been some case histories where chemical packers have been effectively used as barriers for stimulations, existing approaches to multistage fracture operations prohibit chemical packers from being a viable method to provide annular isolation for fracture treatments. Potential challenges are achieving 360-degree coverage when spotting the gel, as well as assuring sufficient length of gel to achieve the required differential rating once the gel packer has set.

Mechanical compression-set packers provide solid annular barriers. There are numerous examples of successful multistage fracture treatments using mechanical packers. Once a packer is set, an immediate annular seal is achieved. However, mechanical packers have a low expansion ratio, and therefore require large packer outside diameters. The large diameters result in small clearances, making installation in long laterals difficult. It is also critical to place the packers in gauged hole sections because of the low expansion ratio and short lengths of the seal elements.

New Options

In many horizontal applications, swellable packers are providing new options for annular isolation in multistage fracture operations. A swellable packer is a short joint of casing that is wrapped with an elastomer that swells when exposed to oil or water (Figure 2). Solid rings are placed on either end of the packer to protect the elastomer during installation and provide an anti-extrusion barrier. As the elastomer absorbs the fluid, the outside diameter of the packer gradually increases to create an annular seal by making full contact with the bore hole wall (Figure 3).

The outside diameter of a standard packer is $\frac{3}{8}$-inch less than the drilled hole diameter. Field experience shows that this is sufficient clearance to install as many as 13 packers in a 10,000-foot lateral. The differential pressure rating is dependent on the seal length as well as the extrusion gap. The extrusion gap is the radial distance between the solid end ring and sealing

FIGURE 2

Swellable Packer

FIGURE 3

Swellable Packer Annular Seal

FIGURE 4

Inflatable Casing Annulus Packer

inside diameter. A seal length of 20 feet is capable of a >10,000 psi differential rating. Swellable packers are simple in that they do not require hydraulic pressure or pipe manipulation to activate.

Inflatable packers (Figure 4) provide a unique advantage in creating annular seals in multistage fracture designs in that they can be inflated with a liquid or a gas. In low-pressure air drilled holes, such as those found in the Appalachian Basin, inflatable packers are often the only option to achieve a positive annular barrier for fracture operations. Inflatable packers have large expansion ratios, and provide larger run-in-hole clearance than mechanical or swellable packers, and can seal in washouts as large as twice the run-in hole diameter.

Fracture Initiation

Inefficient fracture initiation can result in substantial increases in the cost of a hydraulic fracture treatment. There are many contributing factors to an inefficient fracture initiation, including cement design, perforation phasing and density, perforation spacing, and formation stresses. Case histories in the Barnett Shale show that cemented horizontal laterals were more susceptible to inefficient fracture initiation then uncemented laterals. This may be primarily the result of the plane in which the perforations intersect the horizontal bore holes.

The Barnett Shale, and possibly many other similar unconventional plays, cannot be treated as homogenous reservoirs, largely because of the wide variances in stress that can change over the length of a single lateral. Having full access to the annular space during a fracture treatment has proven to be advantageous in achieving lower fracture initiation pressures, and full access to the annular space surrounding the perforations eliminates potential problems with the plane that the perforations intersect the bore hole.

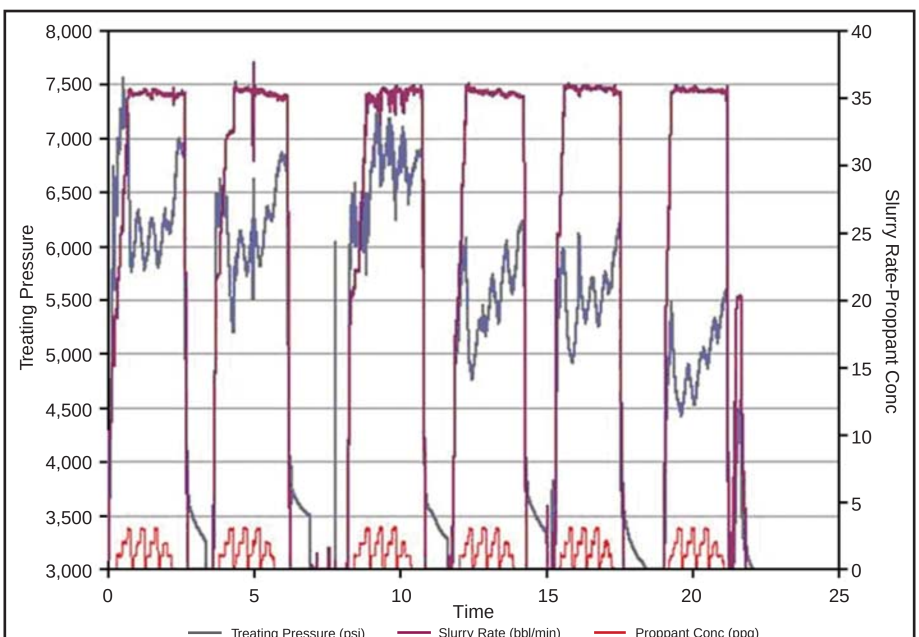
Operators can gain full access to the annular space after a well has been cemented by using acid soluble cement. Before the fracture treatment is pumped, acid is spotted to remove the cement in the area of the perforation cluster, allowing full annular access for the fracture pressure.

By using swellable packers, the cost of cementing and acidizing, as well as any near-well-bore damage associated with these operations, can be eliminated. Swellable packers provide the same positive annular barrier for fracture stimulation as cement while allowing access to the entire annular space between packers for fracture initiation. This ensures that the lowest-stress rocks between the packers are accessible, which promotes efficient fracture initiation.

Experience in the Bakken horizontal oil play in the Williston Basin in North Dakota has shown that designing diversion in the fracture treatment can create multiple fractures between swellable packer positions. Although swellable packers have shown tremendous success in the Bakken, careful analysis is needed to determine if swellables will aid in achieving desired fracture results in other formations. A time-tested adage in hydraulic well fracturing design is that "no two rocks are the same," which translates into the fact that no one multistage design is good for every formation.

FIGURE 5

Multistage Fracture Treatment



Annular Space Access

There are a number of methods that can be used to access the annular space for fracture treatments. If the casing is cemented, perforations are used to access the formation, with perforation clusters spaced along the length of the lateral. Cluster spacing is a factor of reservoir characteristics and fracture geometry. Between each stage, a composite bridge plug is set as a new bottom, and the zone above it is perforated and then fractured. After all stages are complete, the bridge plugs are drilled out.

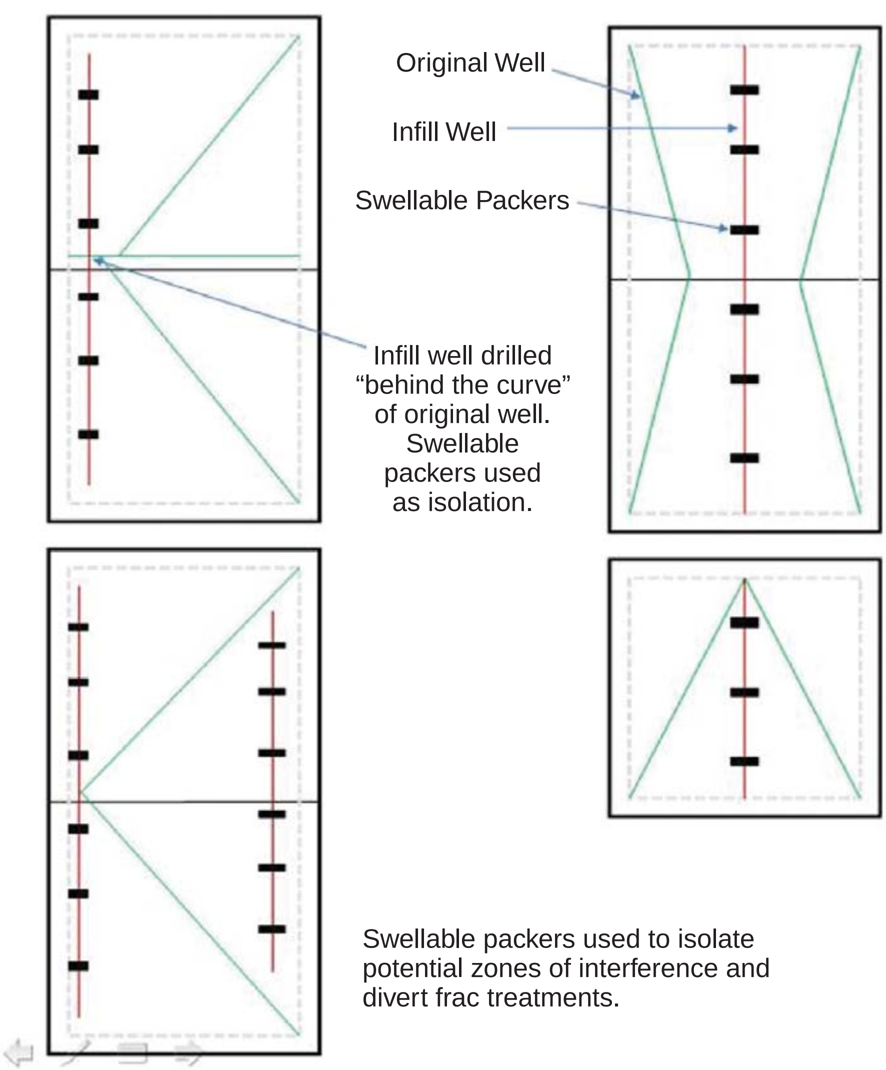
If the casing is not cemented, a mechanical shifting sleeve can be used with annular packers. The frac sleeves are operated by dropping balls that land on the sleeve. Pressure is applied until pins in the packer are sheared and a sliding sleeve is opened. Subsequent balls are dropped to seal off the last treated interval and begin the next stage. The number of stages is limited by the number of balls that can be dropped. Once all stages are complete, the well can be unloaded and the balls flow back and are captured at surface. If access to the full length of well bore is needed at a later date, the ball seats have to be drilled out.

There is also a "plug-and-perf" method that has been widely used in the Bakken formation. The completion design is to run a noncemented liner with swellable packers. The toe joint of the liner is predrilled and the first stage of the treatment is pumped through the predrilled joint. At the end of the treatment, a plug and perforation gun assembly is pumped down on wireline. After the plug is set, the guns disconnect and two to three clusters of perforations are shot while pulling out of the hole. The second stage is then pumped. Each stage includes diversion design in the fracture treatment to create multiple fractures within the stages. In essence, each stage is a mini multistage job.

Figure 5 shows an example of a multistage fracture treatment using swellable packers and the plug-and-perf method between each stage. Note that each "stage" is really four ministage treatments. This creates multiple fractures between each swellable packer. Although the plug-and-perf method is operationally more intensive then the ball-actuated frac sleeve method, the initial production results substantiate using the plug-and-perf method.

FIGURE 6

Infill Well Placement



Refrac And Infill Drilling

Production from a horizontal well that has been treated with a multistage fracture treatment can be increased by refracturing the well as some point in the production decline. As the pressure in the well drainage area declines, the stresses will change. This change in stresses allows new rock to be touched with a refrac instead of pumping into the existing fractures.

Although annular isolation is not always required for refracturing, annular isolation integrity can become an issue when attempting a refrac. As the stresses change in the drainage area, there will be stress changes at the bore hole wall. Whatever isolation method is used, it is often important to maintain an effective annular seal to achieve a successful refrac. Cement is reliable in this instance. Swellable packers are flexible enough to be able to maintain a seal while stresses in the bore hole walls change. In the event of breakout during depletion, swellable packers can continue to increase in outside diameter and re-establish a seal.

Infill drilling programs are under way or are being considered for many reservoirs in which horizontal wells and multistage treatments have emerged as the preferred field development option. Infill wells provide the opportunity to improve underperforming drill sections or place wells outside an existing well bore's drainage area. While refrac adds fractures within the drainage area of a well bore, infill wells touch new rock.

Drilling infill wells may require a trajectory that comes close to existing well bores. In those cases, annular isolation is critical to protect existing well bores. In the situation where the infill well is close to existing well bores, swellable packers can be used to isolate intervals from the multistage fracture treatment. Figure 6 illustrates how infill wells can be placed between existing well bores, using swellable packers to protect them.

While there is no single solution for annular isolation that fits every fracturing application, swellable packers and accessory tools can provide a better and more cost effective way to turn marginal wells into economic successes while increasing reservoir recovery. ❐

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